BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

----In the Matter of----	)	
	)	
PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 03-0371
	)	
Instituting a Proceeding to	)	
Investigate Distributed Generation	)	
in Hawaii.	)	
	)	

DECISION AND ORDER NO. 22248

Filed Jan. 27, 2006

At 11 o'clock A .M.

Karin Higa [signature]

Chief Clerk of the Commission

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

----In the Matter of---- PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Distributed Generation In Hawaii.	Docket No. 03-0371 Order No. 22248

DECISION AND ORDER

By this Decision and Order, the commission sets forth certain policies and principles for the deployment of distributed generation in Hawaii and certain guidelines and requirements for distributed generation, some of which will be further defined by tariff as approved by the commission.

I.

Introduction

A.

Background

By Order No. 20582, issued on October 21, 2003, the commission instituted a proceeding to examine the potential benefits and impacts of distributed generation on Hawaii's electric distribution systems and market.[1] Distributed

[1]Hawaii Revised Statutes ("HRS") §§ 269-7 and 269-15 and Hawaii Administrative Rules ("HAR") § 6-61-71 authorize the commission to examine and institute proceedings on any matter relating to a utility's practices and services or otherwise

generation involves the use of small scale electric generating technologies installed at, or in close proximity to, the end-user's location. Through this docket, the commission's intent was to address generic distributed generation issues affecting the electric industry in Hawaii. These issues include, but are not limited to: (1) addressing interconnection matters; (2) determining who should own and operate distributed generation projects; (3) identifying what impacts, if any, distributed generation will have on Hawaii's electric distribution systems and market; (4) defining the role of regulated electric utility companies and the commission in the deployment of distributed generation in Hawaii; (5) identifying the rate design and cost allocation issues associated with the deployment of distributed generation facilities; and (6) developing any necessary revisions to the integrated resource planning ("IRP") process.[2]

By Order No. 20582, filed on October 21, 2003, the commission made Hawaiian Electric Company, Inc. ("HECO"), Maui Electric Company, Ltd. ("MECO"), Hawaii Electric Light Company, Inc. ("HELCO") (collectively, the "HECO Utilities"), Kauai Island Utility Cooperative ("KIUC"), and the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs

---

affecting the relations and transactions between the utility and the public.

[2]The commission also intends to address any related issues raised in Informal Complaint No. IC-03-098, filed by Pacific Machinery, Inc., Johnson Controls, Inc., and Noresco, Inc. against the HECO Utilities on July 2, 2003.

("Consumer Advocate")[3] parties to this proceeding.[4] The commission also invited interested persons or entities to file motions to intervene or participate without intervention within twenty (20) days of the filing of Order No. 20582, pursuant to HAR Chapter 6-61.[5]

Motions to intervene were timely filed by Life of the Land ("LOL"), Hawaii Renewable Energy Alliance ("HREA"), Johnson Controls, Inc. and Pacific Machinery, Inc. (collectively, the "Hawaii Energy Services Companies"), County of Maui ("COM"), Hess Microgen, LLC ("Hess"), and The Gas Company, LLC ("TGC").[6] The County of Kauai ("COK") filed a timely motion to participate or intervene, and the Department of Business, Economic Development, and Tourism ("DBEDT") timely filed a motion to participate without intervention.[7]

By Order No. 20832, filed on March 3, 2004, the commission granted the motions to intervene by LOL, HREA,

---

[3]Pursuant to HAR § 6-61-62, the Consumer Advocate is an <u>ex officio</u> party to all commission proceedings.

[4]Order No. 20582 at 3.

[5]<u>Id.</u> at 4-5.

[6]On October 31, 2003, LOL filed a motion to intervene. On November 6, 2003, HREA filed a motion to intervene. On November 7, 2003, Hawaii Energy Services Companies filed their motion to intervene. On November 10, 2003, COM, Hess, and TGC filed separate motions to intervene.

[7]On November 6, 2003, COK and DBEDT filed a motion to participate or intervene, and a motion to participate without intervention, respectively.

Hawaii Energy Services Companies,[8] COM, Hess, and TGC[9] (collectively, the "Parties"). By the same order, the commission granted the motions to participate without intervention by DBEDT[10] and COK (collectively, the "Participants"). The commission also ordered the Parties and Participants to meet informally to formulate the issues, procedures, schedule, and the extent or degree of COK's and DBEDT's participation with respect to this docket, to be set forth in a stipulated prehearing order.

On April 2, 2004, the Parties and Participants filed their Proposed Stipulated Prehearing Order for commission review and approval. On April 23, 2004, the commission issued Prehearing Order No. 20922, which approved and adopted in part, and denied in part, the Parties' and Participants' Stipulated Prehearing Order, filed on April 2, 2004.[11] By the same order, the commission required the Parties and Participants to briefly explain in their Preliminary Statements of Position why the issues they proposed were pertinent and needed to be addressed by the commission in this proceeding.

---

[8]By Order No. 21187, issued on July 29, 2004, the commission approved the Hawaii Energy Services Companies' request to withdraw from this docket.

[9]By Order No. 21187, issued on July 29, 2004, the commission approved TGC's request to withdraw from this docket.

[10]By Order No. 21228, filed on August 9, 2004, the commission approved DBEDT's request to withdraw from this docket.

[11]By Order No. 21036, filed on June 9, 2004, the commission amended Prehearing Order No. 20922 by amending Section VII, entitled "COPIES OF TESTIMONIES, EXHIBITS, AND INFORMATION REQUESTS," of the Parties' and Participants' Proposed Stipulated Prehearing Order (Exhibit 1) attached to Prehearing Order

On May 3 and 6, 2004, COK and COM filed their Preliminary Statements of Position, respectively. Thereafter, on May 7, 2004, Hess, DBEDT, LOL, KIUC, HREA, TGC, Hawaii Energy Services Companies, the HECO Utilities, and the Consumer Advocate filed their Preliminary Statements of Position.

After the Preliminary Statements of Position were filed, the Parties and Participants served information requests ("IRs") on each other as to their Preliminary Statements of Position.[12] Responses to the IRs on their Preliminary Statements of Positions were served several weeks after receipt of the IRs.[13]

No. 20922 by requiring the Parties and Participants to file the original plus ten (10) copies of documents filed with the commission instead of the original plus eight (8) copies. In addition, the commission required the Parties and Participants to provide an electronic copy of all past and future filings with the commission.

By Order No. 21117, issued on July 13, 2004, the commission allowed: (1) the Parties and Participants to file two-sided copies of pleadings, briefs, and other documents, and (2) pleadings, briefs, and other documents to be post-marked on the dates set forth in the Stipulated Regulatory Schedule rather than filed at the office of the commission in Honolulu for neighbor island Parties and Participants.

[12]On May 21, 2004, HREA served IRs on the Parties' and Participants' Preliminary Statements of Position. On May 24, 2004, COK, COM, TGC, Hawaii Energy Services Companies, Hess, KIUC, LOL, the HECO Utilities, and the Consumer Advocate served IRs to the Parties and Participants on their Preliminary Statements of Position.

[13]On June 16, 2004, COM, DBEDT, KIUC, TGC, LOL, Hess, HREA, the Consumer Advocate, and the HECO Utilities filed their Responses to IRs on their Preliminary Statements of Position.[13] On June 17, 2005, COK filed its Responses to IRs on its Preliminary Statement of Position.

On June 23, 2004, the commission held a status conference with the Parties and Participants.[14] Thereafter, on July 13, 2004, COK filed its written Direct Testimonies, Exhibits and Workpapers. The following day, on July 14, 2004, DBEDT, HREA, Hess, LOL, the Consumer Advocate, the HECO Utilities, and KIUC filed their written Direct Testimonies, Exhibits and Workpapers. On July 15, 2004, COM filed its written Direct Testimonies, Exhibits and Workpapers.

After the filing of the written Direct Testimonies, Exhibits and Workpapers, the Parties and COK (as DBEDT, the only other participant, withdrew from the docket on August 9, 2004) served additional IRs regarding the written Direct Testimonies, Exhibits and Workpapers.[15] After responses to those IRs were served, the Parties and Participant (COK) served Supplemental

[14]A Notice of Status Conference was issued on June 15, 2004. A status conference was held on June 23, 2004, at 3:00 p.m. in the commission hearing room.

[15]On July 28, 2004, COK, KIUC, LOL, Hess, the Consumer Advocate, the HECO Utilities, and HREA filed IRs to the Parties and Participants on their written Direct Testimonies, Exhibits and Workpapers. On July 29, 2004, COM filed its IRs to the Parties and Participants on their written Direct Testimonies, Exhibits and Workpapers.

On August 18, 2004, LOL, KIUC, the Consumer Advocate, Hess, HREA, and the HECO Utilities filed their Responses to IRs filed by the Parties and Participants on their written Direct Testimonies, Exhibits and Workpapers. On August 19, 2004, COM filed its Responses to IRs filed by the HECO Utilities, the Consumer Advocate, HREA, LOL, and Hess on their written Direct Testimonies, Exhibits and Workpapers. On August 27, 2004, COM filed its Responses to IRs filed by KIUC on COM's written Direct Testimonies, Exhibits and Workpapers.

Information Requests ("SIRs") concerning the Parties' and Participant's responses to the additional IRs.[16]

On October 22, 2004, HREA, KIUC, the Consumer Advocate, and the HECO Utilities filed their written Rebuttal Testimonies, Exhibits and Workpapers.[17] On October 25, 2004, COK and COM filed their written Rebuttal Testimonies, Exhibits and Workpapers.

After written Rebuttal Testimonies, Exhibits and Workpapers were filed, the commission issued IRs to the Parties and Participant on October 28, 2004. Several days later, the Parties and Participant served Rebuttal Information Requests ("RIRs") on each other as to their written Rebuttal Testimonies, Exhibits and Workpapers.[18]

---

[16]On September 2, 2004, HREA served SIRs to the Parties and Participant on their Responses to IRs. On September 3, 2004, LOL, KIUC, Hess, the Consumer Advocate, and the HECO Utilities filed SIRs to the Parties and Participant on their Responses to IRs. On September 7, 2004, COM filed its SIRs to the Parties and Participant on their Responses to IRs.

On September 16 and 17, 2004, COM, Hess, HREA, KIUC, the Consumer Advocate, and the HECO Utilities filed their Responses to SIRs served by the Parties and Participant on their Responses to IRs.

[17]On September 30, 2004, the commission held a status conference with the Parties and Participant. A Notice of Status Conference was issued on September 15, 2004. An Amended Notice of Status Conference was issued on September 16, 2004. By letter dated September 29, 2004, HECO requested the status conference be rescheduled from 1:30 to 2:00 p.m. By letter issued on September 30, 2004, the commission rescheduled the status conference from 1:30 to 2:00 p.m. A status conference was held on September 30, 2005, at 2:00 p.m. in the commission's hearing room.

[18]On November 1, 2004, KIUC, the Consumer Advocate, HREA and the HECO Utilities filed RIRs to the Parties and Participant on their written Rebuttal Testimonies, Exhibits and Workpapers. On November 3, 2004, COM filed its RIRs to the Parties and Participant on their written Rebuttal Testimonies, Exhibits and

On November 22, 23, and 24, 2004, HREA, Hess, the HECO Utilities, KIUC, the Consumer Advocate, COK, COM, and LOL filed their Prehearing Conference Statements.[19] Thereafter, on November 29, 2004, the commission held a prehearing conference with the Parties and Participant.[20]

On December 1, 2004, the commission issued Prehearing Order No. 21489, which: (1) modified the hearing to a panel format; (2) required the Parties and Participant to notify commission counsel as to the witnesses that would be assigned for each panel by December 1, 2004; (3) required the Parties and Participant to meet informally to agree to an order of cross-examination and notify commission counsel on the agreed order of cross-examination; and (4) notified the Parties and Participant that the commission will distribute to the Parties and Participant an agenda for the hearing by December 3, 2004, and

---

Workpapers. LOL, HREA, the HECO Utilities, Hess, KIUC, the Consumer Advocate, COK and COM filed their Responses to RIRs served by the Parties and Participant on their written Rebuttal Testimonies, Exhibits and Workpapers and to the commission's IRs on November 22 and 23, 2004. On December 6, 2004, COM filed a supplemental response to HECO/Maui-DT-SIR-7.

[19]On November 22, 2004, HREA, Hess, the HECO Utilities, KIUC, and the Consumer Advocate filed their Prehearing Conference Statements. On November 23, 2004, COK and COM filed their Prehearing Conference Statements. On November 24, 2004, LOL filed its Prehearing Conference Statement.

[20]By letter dated November 1, 2004, the commission scheduled a prehearing conference for November 29, 2004, at 10:00 a.m., and requested the filing of Prehearing Conference Statements by November 22, 2004.

required the Parties and Participant to submit any request for changes by December 6, 2004.[21]

On November 30, 2004, the Consumer Advocate submitted the names of its panelists and cross-examiner. On December 1, 2004, Hess and the HECO Utilities submitted the names of their panelists and cross-examiners. On December 2, 2004, COK submitted the names of its panelists and cross-examiner.

On December 3, 2004, the commission issued a draft hearing agenda for the hearing scheduled for December 8-10, 2004, and requested that any changes be submitted by December 6, 2004. On December 7, 2004, the commission issued: (1) a final hearing agenda; (2) a copy of an outline of the commission's likely areas of questioning; and (3) a copy of the commission's docket entries listing.

A panel hearing was held on December 8, 9, and 10, 2004, in which the commission held open discussions with each of the panelists and experts for each party and participant, and each party and participant was allowed to ask questions of each of the other parties and participant's panelists and experts, in order to develop as fully as possible the merits of each of the issues before the commission.[22]

---

[21]On September 17, 2004, the commission issued a Notice of Evidentiary Hearing to be held on December 8-10, 2004, at 9:00 a.m., in the commission hearing room.

[22]The December 8, 2004 hearing was held at the commission's hearing room located at 465 South King Street, Room B-3, Honolulu, Hawaii. The December 9 and 10, 2004 hearings were held at the State Capitol, located at 415 South Beretania Street, Room 329, Honolulu, Hawaii.

After the hearing, by letter dated December 28, 2004, the commission notified the Parties and Participant to address certain issues in their post-hearing briefs.[23] Post-hearing opening briefs[24] and reply briefs[25] were filed by the Parties and Participant in March 2005.[26]

---

[23]The commission requested that the Parties and Participant address the following issues in their post-hearing opening briefs: (1) Whether the costs and benefits of distributed generation change in times of excess capacity versus times of shortages of capacity; if the answer is yes, then given that for the life of any long-term asset there are likely to be periods of excess capacity and shortages, please comment on the time span over which one should measure the costs and benefits of distributed generation; (2) How should non-utility owned distributed generation be incorporated into the IRP process, in a manner comparable to the treatment of utility-owned distributed generation, so that there is no market or regulatory advantage of one type over another; (3) Whether transmission and distribution costs will be substantially reduced for combined heat and power or other distributed generation projects set up for peak shaving only; (4) Whether potential loss of revenues to investor owned utilities, due to advancements in technology and the development of new markets is a risk for which the utility has been and is compensated through its approved rate of return; and which forms of distributed generation, if any, would fall into the category of advancement risks for which the utility already receives compensation; (5) Whether the utility would have stranded costs in a period of load growth; (6) Is it reasonable to expect identification of individual projects or project zones in the IRP process? What specific modifications to the IRP process should the commission consider to facilitate such identification; (7) Under each of the two scenarios for participation in distributed generation - utility participation and utility affiliate participation - what rules and restrictions are necessary to assure that the competition between non-utility projects and utility-owned (or affiliate-owned) projects is evenhanded, meaning that the utility or utility affiliate has no unearned competitive advantage.

[24]On March 4, 2005, LOL filed its Post-Hearing Opening Brief. On March 7, 2005, KIUC, Hess, HREA, the HECO Utilities, and the Consumer Advocate filed their Post-Hearing Opening Briefs. On March 8 and 9, 2005, COK and COM filed their Post-Hearing Opening Briefs, respectively.

B.

Issues

A. Principles and Policies for the Deployment of Distributed Generation

B. Ownership of Distributed Generation

C. Costs and Benefits of Distributed Generation

D. Forms of Distributed Generation that Are Feasible and Viable in Hawaii

E. Revisions to the IRP Process

F. Reliability and Safety Matters

G. Standardized Interconnection Agreement and Process

1. Interconnection

2. Pre-Interconnection Studies

3. Distribution System Upgrades Required For Integration

4. Responsibility for Control and Operation of Distributed Generation Equipment

5. Indemnification and Liability Insurance

By letter filed on March 3, 2005, Hess requested that it be allowed to file a supplemental opening brief, which would be limited to addressing the calculation relating to the minimum number of kWh that a customer would have to purchase to recover the demand-related charges properly attributable to that customer that in the current rate design are recovered through the energy charge. By letter dated February 25, 2005, HECO indicated that it was still working on this calculation which it represented at the December 10, 2004 hearing it would prepare. On April 26, 2005, HECO submitted its analysis. On May 10, 2005, Hess informed the commission that it will not be filing a supplemental opening brief.

[25]On March 24, 2005, LOL filed its Post-Hearing Reply Brief. On March 28, 2005, Hess, KIUC, HREA, the Consumer Advocate, and the HECO Utilities filed their Post-Hearing Reply Briefs. On March 30, 2005, COM filed its Post-Hearing Reply Brief.

[26]On February 8, 2005, the commission provided notice to the Parties and Participant of the receipt of the official transcript.

6. Utility Communication With Customer-Generators

H. Cost Allocation and Rate Design

1. Interconnection Costs

2. Standby and Backup Service Costs

3. "Unrecovered" Costs

I. Other Issues

1. Informal Complaint No. IC-03-098

2. Net-Metering Facilities

II.

Discussion

A.

Principles and Policies in the Deployment of Distributed Generation

The policy of the commission is to promote the development of a market structure that assures: (a) distributed generation is available at the lowest feasible cost; (b) distributed generation that is economical and reliable has an opportunity to come to fruition; and (c) distributed generation that is not cost-effective does not enter the system.

The commission will take those actions that are necessary to promote the installation of distributed generation that is economically efficient and reliable. Those actions include, but are not limited to, the actions listed here and discussed further in this Decision and Order:

(1) Establishing requirements to assure safety and reliability;

(2) Establishing requirements for interconnecting distributed generation to the electric utility's distribution system;

(3) Establishing technical requirements to ensure distribution safety;

(4) Establishing a policy that permits utility participation in the distributed generation market, under specified circumstances;

(5) Establishing the parameters for standardized interconnection agreements;

(6) Requiring the utilities to perform pre-interconnection studies for customers at reasonable cost to the customer;

(7) Establishing requirements and parameters that: (a) allow qualified third parties to perform the pre-interconnection studies, and require the utility to accept them under specified conditions; (b) allow third party verification of alternative solutions and technologies; (c) create safe-harbor exemption from the study requirements for smaller projects whose interconnection is unlikely to affect the distribution system; and (d) pre-certify certain equipment that meets certain standards set by appropriate organizations such as the Underwriters Laboratory ("UL") so as to expedite installation and obviate separately conducted equipment studies;

(8) Requiring the utility to: (a) negotiate or require contracts that allow the utility to dispatch the customer's generation unit where dispatching the unit is economical, and

(b) make payments to the customer-generator for the dispatch, reflecting costs avoided by the utility;

(9) Refraining from requiring distributed generators to carry a standardized amount and type of liability insurance and precluding the utility from requiring the same;

(10) Requiring that the utility-incurred costs that benefit the distributed generation project are borne by the distributed generation project and the charges for these utility-provided services are properly allocated;

(11) Requiring the interconnection customer to pay for all costs of interconnecting, including costs of system upgrades or network upgrades, with certain exceptions;

(12) Requiring each utility to establish unbundled rates that identify the costs associated with providing each service (i.e., generation, distribution, transmission and ancillary services) to determine standby rates; and

(13) Considering whether there is a benefit to deferring the assignment of any unrecovered costs until a certain percentage of load has been lost to distributed generation.

B.

Ownership of Distributed Generation

In this investigation, the commission, Parties and Participant identified a number of possible ownership alternatives for distributed generation, including: (a) customer-owned facility on a customer's site; (b) third party-owned facility on a customer's site; (c) utility-owned facility on utility property (d) third party-owned facility on utility property; and (e) utility-owned facility on a customer's site.

As for alternatives (a) and (b), which involve customer or third party-owned facilities on a customer's site, the commission has little or no jurisdiction until the customer seeks to interconnect with the utility's system. The interconnection standards established for the utility and approved by the commission will then be applicable, as discussed further herein.

Under alternatives (c) and (d), there is no dispute that the utility should be authorized to procure and operate distributed generation for utility purposes[27] on utility property or contract with a third party to construct and operate distributed generation on utility property.

Under alternative (e), however, the Parties strongly disagree on whether the utility ought to be authorized to own and operate distributed generation that is located on a customer's site. The Consumer Advocate's position is that utilities, customers, and third party vendors should be allowed to own and operate distributed generation facilities that are located on customer premises.[28] KIUC's position is that utility ownership of distributed generation projects should be allowed and even

---

[27]Distributed generation used for "utility purposes" would include substation-sited generation that is owned and controlled by the utility to (a) perform a generation peaking function, or (b) address case-specific transmission or distribution problems.

[28]Consumer Advocate's Post-Hearing Brief, filed on March 7, 2005, at 9.

encouraged on Kauai.[29] The HECO Utilities' position is that utilities should be allowed to provide energy efficient combined heat and power ("CHP") systems to their customers.[30] Hess prefers the option of allowing the utility to provide distributed generation as a regulated service with the commission's oversight.[31] HREA's position is that an investor-owned utility should not be involved directly in distributed generation projects on the customer-side of the meter.[32] COM's position is that before the HECO Utilities' regulated service participation option is considered, the HECO Utilities should first demonstrate that their option is better than privately owned distributed generation DSM programs options.[33] COK's position is that the commission should consider implementing rules and restrictions governing access to customer and network information so that any subdivision or affiliate of a utility is provided no more information than its non-utility related competitor.[34]

The HECO Utilities proposed that they be allowed to provide customer-sited distributed generation services as a regulated service. Allowing the utility to provide distributed

---

[29]KIUC's Post-Hearing Opening Brief, filed on March 7, 2005, at 18.

[30]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 1-2.

[31]Tr. (12/9/04) at 45-46 (Gregg).

[32]HREA's Post-Hearing Opening Brief filed on March 7, 2005, at 20.

[33]COM's Final Brief, filed on March 9, 2005, at 20.

[34]COK's Post-Hearing Opening Brief, filed on March 7, 2005, at 9-10.

generation as a regulated service has at least two advantages: (1) it can stimulate and satisfy the demand for new generation equipment in a newly emerging distributed generation market; and (2) it can assure that there is at least one entity available in the market to provide distributed generation services.

However, allowing the utility to provide distributed generation on a customer's site, as a regulated service, has disadvantages as well. It may create an entry barrier for prospective competitors to the extent the utility has market advantages attributable to its historic status as the sole provider of electric retail service, rather than its present merits as may be related to a particular distributed generation project. Allowing the utility to provide distributed generation on a customer's site also may shift the risks and expenses of this new business onto the utility's captive ratepayers and away from the customers it is trying to attract. The utility would also have an opportunity to dominate the new market, whereas electricity customers may be better served if they have alternatives that multiple and diverse suppliers of distributed generation services would bring.

In weighing the advantages and disadvantages of allowing a utility to provide distributed generation services and own and operate a distributed generation project on a customer's site, the commission finds that the disadvantages outweigh the advantages and the utility should not be allowed to provide distributed generation services on a customer-owned site as a regulated service, except under the circumstances described herein.

Ideally, an effectively competitive distributed generation market requires the presence of multiple, viable sellers who are aggressively vying for customers, while operating independently from the utility and conducting their transactions through arm's length relationships with the utility. No party should have an unearned advantage by virtue of a special relationship with the utility's unique resources. However, Hawaii's present market conditions are far from optimal. The HECO Utilities represent that they need additional capacity in the short term.[35] The HECO Utilities are also the only entities under a regulatory obligation to supply electricity to their customers. Based on the record in this case, which included no specific entities indicating readiness and ability to supply distributed generation in Hawaii, the commission must assume that the HECO Utilities are the only entities immediately able to meet the State's capacity needs and to deploy distributed generation to do so. It would not be in the public interest to exclude the HECO Utilities from providing distributed generation services at this early stage of distributed generation market development.

Allowing the utility to provide customer-sited distributed generation services to customers as a regulated service has both benefits and risks. Absent other providers of

[35] HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 44-45.

distributed generation, the utility presence can both stimulate and satisfy demand for new generation equipment. Stimulation of demand, however, does not mean that the market becomes more competitive. A competitive market will supply the growing demand only if new competitors can enter the market to meet the new demand. If prospective competitors face entry barriers, they will not enter the market. In that case, the new demands stimulated by the utility will be met by the utility alone.

Despite the risk that utility involvement may deter the development of a competitive market, two factors support allowing the utility to participate in the immediate term. The first factor is the need for supply options to meet the projected growing need for electricity. The second is that the utility, at present, is the most informed potential provider of distributed generation and has the most knowledgeable staff and the most current data with respect to Hawaii-specific requirements. To eliminate these resources as a customer option conflicts with our goal of making available all economic options. To eliminate the most informed potential provider without assurance of a fully competitive market, at a time of projected capacity shortage, may not be prudent.

The commission recognizes that the two aforementioned goals -- meeting the short-term need for capacity and encouraging the longer-term development of a competitive market for distributed generation -- are in tension. The solution must satisfy the first goal without impeding the second.

Accordingly, the commission concludes that utilities should be allowed to participate in the customer-sited distributed generation market either as: (1) an affiliate as described below; or (2) as a regulated utility, upon a showing that: (a) the proposed distributed generation project would resolve a legitimate system need; (b) it is the least cost alternative to meet that need; and (c) in an open and competitive process acceptable to the commission, the customer-generator was unable to find another entity ready and able to supply the proposed distributed generation service at a price and quality comparable to the utility's offering, as described further below.

Requiring the utility to provide distributed generation through an affiliate has at least four advantages over direct utility participation. First, it creates a structure that, in theory, prevents improper cost-shifting because the affiliate will be required to maintain a separate set of books, and the commission can require pricing rules for inter-affiliate transactions that prevent cross-subsidies or unearned advantages. Second, the commission can require that the affiliate be treated by the utility like any other non-affiliated business entity. Treating all entities evenhandedly encourages vigorous competition among potential distributed generation providers, thereby fostering the commission's goals of providing generation resources to customers at the lowest possible costs. Third, it limits the unearned advantages from the monopoly utility since inter-affiliate transaction rules can limit the number of shared officers and facilities between the entities, define the allowable transactions between the two entities, and establish rules for acquiring goods and services from one affiliate to the other. Fourth, it promotes nondiscriminatory access to the distribution system and other bottleneck facilities or services since the affiliate, just like other non-affiliated companies, needs access to the distribution system and to customer information.

The commission recognizes that requiring the utility to provide distributed generation through an affiliate may have disadvantages. The HECO Utilities, for example, stated that they do not anticipate participating in the distributed generation market if only a separately capitalized, separately staffed affiliate was allowed to participate.[36] The commission, however, does not have sufficient evidentiary basis to conclude that, in fact, if there were an affiliate requirement for the utility to participate in customer-sited distributed generation, the utility would actually decline to participate. If investments in distributed generation are profitable for unaffiliated suppliers, the commission has seen no evidence to support a conclusion that the HECO Utilities would forego this opportunity for profit by declining to create an affiliate.

Another possible disadvantage of requiring the utility to provide distributed generation through an affiliate is the potential loss of the economies of scale and scope, which loss could result in higher costs to consumers. However, this

[36]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 74-75.

theoretical loss of economies of scale and scope, sometimes referred to as "static" efficiency, could be offset by increases in "dynamic" efficiency resulting from the head-to-head competition among new suppliers of distributed generation services.

If the utility wishes to sell distributed generation services through an affiliate, it must do so in an arm's length transaction and through a relationship with the affiliate that is acceptable to the commission. The commission hereby requires that each utility establish detailed affiliate requirements, by tariff for approval by the commission, to ensure an arm's length relationship, if the utility elects to sell distributed generation services through an affiliate. Those requirements shall (1) define the permissible types and pricing of transactions between affiliated entities; and (2) establish a code of conduct with respect to behavior in competition. This code of conduct will address issues such as nondiscriminatory access to customer information and access to distribution facilities, where the absence of such access might give the utility an unearned advantage. Such requirements should produce the dual benefits of evenhanded competition and prevent cross-subsidies by the monopoly customers.

If the utility wishes to sell distributed generation services as a regulated utility, the utility must show, in an application filed with the commission, the following:

(a) the distributed generation resolves a legitimate system need;

(b) the distributed generation proposed by the utility is the least cost alternative to meet that need; and

(c) in an open and competitive process acceptable to the commission, the customer-generator was unable to find another entity ready and able to supply the proposed distributed generation service at a price and quality comparable to the utility's offering.

The commission may establish further detailed guidelines on the foregoing application requirements by rule or order, if circumstances indicate that these requirements are insufficient to achieve the goals described in this Decision and Order.

By establishing the preceding conditions to utility participation in the distributed generation market, the commission seeks to allow utility participation to address immediate system needs when required in a manner that minimizes the possibility that utility participation will impede entry of new competitors in the immediate and longer term.

C.

Costs and Benefits of Distributed Generation

One purpose of the commission's investigation is to examine the potential benefits and costs of distributed generation. The commission's investigation revealed that distributed generation can provide benefits by: (a) deferring the need to deploy certain facilities such as lines and transformers, on the transmission system and distribution system, which may be needed to avoid overloads, under contingency and projected peak conditions;[37] (b) reducing system transmission and distribution line losses and providing voltage support;[38] (c) deferring or avoiding certain utility costs, including new central station generating capacity and fixed operation and maintenance ("O&M") costs (avoided capacity costs),[39] utility central station generation fuel and variable O&M costs to the extent distributed generation units displace utility generated energy (avoided energy costs),[40] and new transmission and distribution ("T&D") capacity, depending on the specific nature of an area's T&D system and the ability to site distributed generation there (avoided T&D costs);[41] (d) tailoring distributed generation installed at the end-user's site to meet the user's specialized energy needs;[42] (e) improving energy efficiency with respect to certain distributed generation technologies that use fossil fuels, such as CHP systems;[43] (f) providing an enhanced ability to switch to new technologies due to lower incremental costs;[44] (g) with respect to certain renewable energy technologies,

[37]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 83.

[38]Id.

[39]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 101.

[40]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 101.

[41]Id.

[42]Id. at 104.

[43]Id. at 105.

[44]Id.

avoiding the burning of fossil fuels, reducing overall fossil fuel consumption and air pollution - wind turbines and photovoltaic systems are the most likely form of renewable distributed generation;[45] (h) allowing generation capacity to be added incrementally, which is better suited to meeting the load growth of small utility systems like those in Hawaii;[46] and (i) increasing overall reliability of the island grids, i.e., the addition of more generators on the system increases the overall reliability of a utility's generation resource.[47]

The commission's investigation also revealed possible negative effects of distributed generation, such as increased air emissions, noise, and visual impacts.[48] The interconnection of distributed generation can also create costs for the electric utility that it would not otherwise incur to maintain electric system safety or reliability. For example, distributed generation can: (a) increase the risk of voltage regulation problems or may unsettle the utility's protection system, resulting in unintended islanding (electrical isolation);[49] (b) adversely affect the reliability of the distribution system, such as if the short circuit contribution ratio of the

---

[45]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 106.

[46]COM's Final Brief, filed on March 9, 2005, at 10.

[47]HREA's Post-Hearing Opening Brief, filed on March 7, 2005, at 4.

[48]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 105-06.

[49]_Id._ at 84.

distributed generation facility is too great or if the distributed generation facility is interconnecting into the utility's network systems.[50]

The commission notes that not all of the benefits and costs identified above will exist for each distributed generation project. Many of the benefits of distributed generation depend on how the facilities are planned, installed, and operated. The costs and complexity of interconnection also vary widely, depending on the size, application, location, and technology of the distributed generation facility, and the configuration of the distribution system to which it connects.

D.

Forms of Distributed Generation That are Feasible and Viable in Hawaii

The HECO Utilities and KIUC proposed that the commission use specific criteria to determine whether distributed generation is feasible and viable. The HECO Utilities propose that the distributed generation will have to be: (1) technically feasible; (2) commercially available; (3) economically viable (i.e., cost-effective versus other options); (4) price competitive in the short-term; (5) sustainable in the long-term (i.e., backed up by adequate infrastructure support with respect to O&M and fuel); (6) able to address site-specific constraints

[50]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 84.

(i.e., with respect to permitting); and (7) able to meet the needs of customers.[51]

KIUC proposed the following factors that should be considered in assessing what forms of distributed generation are feasible and viable in Hawaii: dispatchability, ability to be a reliable and constant supply source, and demonstration as a fully commercialized technology.[52]

Since not all benefits and costs identified with distributed generation exist for each distributed generation project,[53] the commission will not require all projects to satisfy all possible criteria to be considered distributed generation for purposes of the rights and obligations established by this Decision and Order.

E.

Revisions to the IRP Process

The IRP process[54] requires the utilities to conduct long-term resource planning, including consideration of demand-side and supply-side resource options. The commission monitors the utilities' resource planning activities to assure that there is an adequate and cost-effective supply of electric

[51]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 50.

[52]Tr. (12/8/04) at 25 (Friedman).

[53]See discussion in Section II.C.

[54]Order No. 11523, issued on March 12, 1992, in Docket No. 6617, as amended by Decision and Order No. 11630 issued on May 22, 1992.

power sufficient to meet the present and future loads. Central to each resource plan is an accurate load forecast.[55] The utilities' plans must predict future demand for electricity and the best combination of supply and demand reduction resources to meet the forecasted demand.

The utility's need for additional capacity affects when new resource additions are necessary. Other factors affecting the timing of new resources include the mix of generation resources, minimum demand considerations, required power purchases, supplemental energy purchases, purchase power uncertainties, transmission considerations, and system stability considerations.[56]

The utilities currently take distributed generation into consideration during the IRP process in generation resource addition and transmission and distribution planning decisions. Once the need for generation capacity is determined, the utilities must evaluate various options to satisfy the need. These options include distributed generation, CHP, renewable energy, and central-station generation.[57] Concerning long-term transmission planning, the HECO Utilities stated that they will

[55]The utilities are required to update their load forecast annually, by producing an Adequacy of Supply Statement. This Statement indicates whether the utility has sufficient generating capacity to meet all reasonably expectable demands for service and provide a reasonable reserve for emergencies. Rule 5.3(a) of General Order No. 7, Standards for Electric Utility Service in the State of Hawaii.

[56]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 136.

[57]Id.

test distributed generation solutions by (a) selecting candidate long-term resource plans (making assumptions about the sizes, locations and operating costs for future central generating station units); and then (b) testing the effect on the transmission system of distributed generation units.[58]

The HECO Utilities assert that distribution planning, in contrast to transmission planning, cannot be incorporated into the long-term IRP process because of the time frame and variability of the distribution system load forecast. The distribution planning process is conducted in a manner consistent with the IRP process on a project-specific basis, to the extent practical. The HECO Utilities, however, stated that they will consider distributed generation in the distribution planning process, however.[59]

To the extent that utility-owned distributed generation is one of the options with which the utility meets its supply-side resource needs, distributed generation should be subject to the same scrutiny applied to other resource additions. The commission, however, will not require utilities to include customer-sited distributed generation projects in their IRP process because the utility has limited means of knowing when or where customer-sited distribution generation will be interconnected to the distribution system. This limitation on the utility's knowledge means that the utility cannot easily make

[58]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at 139-41.

[59]Id. at 141-42.

reliable forecasts of customer-sited distributed generation for inclusion as a supply-side resource in an integrated resource plan. In addition, requiring distributed generators to obtain resource plan approval for a project will create an entry cost for otherwise cost-effective distributed generation projects.

F.

Reliability and Safety

Another issue in this docket was whether distributed generation can be implemented in a manner that does not reduce the reliability or safety of the electric distribution system. Distributed generation differs from conventional generation because generators enter the arena without being planned or controlled automatically, by the local utility. To assure safety and reliability, the commission therefore will require the utilities to establish requirements that: (a) require, provide, and charge for all services necessary to maintain adequacy, security, and stability of the distribution system; and (b) require all necessary safety equipment and operational procedures as a condition for connecting distributed generation to the system.

Despite numerous generators connected to, and injecting power into, the utility system, that system must be in balance at all times. Specifically: (a) generation and demand must be equal; (b) sufficient generation must be available to provide voltage support on the lines; (c) sufficient capacity must exist on the distribution lines to move electricity; and (d) there must be surplus generation, transmission, and distribution capacity available and ready to respond to sudden changes in demand. A new load, a new generation source, or a loss of either can cause system imbalance, with results ranging from damaged computer equipment to large-scale blackouts. Prevention requires coordination between distributed generators and the utility.

The commission, therefore, requires that each utility establish reliability and safety requirements, by proposed tariff for approval by the commission, for distributed generation that is connected to the electric utility's distribution system. These requirements should (a) establish operating standards for voltage, power factors, frequency, and harmonic distortion; (b) require certain procedures and equipment to allow for the transfer of electric power between the system and the facility and allow parallel operation[60] to occur. In such situations, certain limitations should apply: (1) the distributed generation unit should be required to maintain a consistent degree of power flow, stable VAR (or volt amperes reactive) supply and voltage support; (2) the distributed generation unit must be able to synchronize with the electric power system, within an acceptable degree; (3) upon disconnection from the power system, the distributed generation unit should be prohibited from reconnecting to the power system and re-commencing operation until the utility has verified that the unit can reestablish full voltage and power support to the distribution system and operate

[60]Parallel operation means the operation of distributed generation by its owner while the distributed generation facility is connected to the utility's distribution system.

in a stable manner for a specified time period to be established by the utility. Further, the guidelines should establish control and monitoring requirements for the distributed generation unit to coordinate its operations with the utility, as well as: (1) allow for automatic control and quick shutdown; (2) meet metering, telemetry, and communications requirements capable of supplying failure reporting data on generation operation; and (3) meet minimum documentation and test result criteria.

In addition, the interconnection of distributed generation should not result in an unacceptable increase in the risk of electrocution or fire. The commission hereby requires that each utility establish technical requirements, by proposed tariff for approval by the commission, to ensure distribution system safety that: (a) require any distributed generation unit to have a positive disconnect that automatically isolates it from the distribution system when there is a fault; (b) require that when there is a fault, the distributed generation unit may not reconnect to the distribution system until the fault is cleared; (c) require all interconnected distributed generation to have a utility-accessible manual disconnect switch; (d) require all distributed generators to comply with national, state, and local standards and electrical codes and safety practices; (e) require the generator to follow the utility's safety procedures for ensuring that switching devices do not operate unless and until appropriate preconditions are met and verified;[61] and (f) require the distributed generation unit to have protective devices such as over current protection, circuits with reclosing schemes, inverters, synchronizing schemes and islanding abilities.

G.

Standardized Interconnection Agreement and Process

Interconnection is the means by which the distributed generation unit electrically connects to the distribution system. During its investigation, the commission heard testimony regarding the need for technical interconnection requirements to assure the safety, reliability, and timeliness of distributed generation interconnection to the distribution system.

The HECO Utilities' position is that all distributed generation installations, whether utility or non-utility owned, should be subject to technical interconnection requirements to ensure that the distributed generation installations will not cause damage, or pose a safety hazard, or that the systems are not damaged themselves. To ensure this result, the HECO Utilities urged the commission to establish a distributed generation interconnection tariff, interconnection standards, and a standard interconnection agreement, as the commission has done with the Rule 14.H. interconnection tariff.[62] Hess urged that the

[61]For intermediate and larger generators, both the utility and the owner should be responsible for ensuring these procedures are followed.

[62]HECO's Post-Hearing Opening Brief, filed on March 7, 2005, at Exhibit A at 18.

interconnection process be timely, that the customer-generator receive an acknowledgement from the utility to start the clock for processing the interconnection request, and that the customer-generator be able to expedite interconnection by paying for an engineer to evaluate its project.[63]

Technical interconnection requirements require a determination with respect to which distributed generation facilities should be eligible for interconnection and the standard terms and conditions for interconnection. While it is feasible for distributed generation to operate solely for its customer-generator disconnected from the utility's distribution system, many of the benefits of distributed generation previously discussed can be realized only if distributed generation is connected to the distribution system.

The complexity of a distributed generation unit's interconnection with the distribution system varies, depending upon (a) the type of technology, (b) the fuel source, either fossil or renewable, (c) the power system interface, (d) the extent of interaction required between the customer-generator and the utility, and (e) the architecture of the distribution system into which the distributed generation is interconnected.

Requiring each customer-generator to negotiate a complex interconnection agreement anew may create an unnecessary barrier to entry and may discourage the interconnection of small,

[63]Hess' Post-Hearing Opening Brief, filed on March 7, 2005, at 4.

cost-effective distributed generation projects. Accordingly, the commission hereby requires that each utility establish a non-discriminatory interconnection policy, by proposed tariff for approval by the commission, that entitles distributed generation to interconnect when it can be done safely, reliably and economically. The interconnection policy should encompass the following seven areas: (1) interconnection, (2) pre-interconnection studies, (3) distribution system upgrades required for integration, (4) responsibility for control and operation of distributed generation equipment, (5) indemnification and liability insurance, (6) communication with customers, and (7) dispute resolution. Accordingly, the commission also hereby requires the utilities to develop a standardized interconnection agreement, by proposed tariff for approval by the commission, to streamline the distributed generation application review process and eliminate long lead times that may lead to cancellation of a beneficial project, as described in greater detail below.

1. <u>Interconnection</u>

The absence of clear interconnection requirements can produce unnecessary costs, in the form of inflexibility, long-lead times, lack of standardization and possible cancellation of a project beneficial to the customer-generator and the utility's customers.

The commission hereby requires each utility to establish, by proposed tariff for approval by the commission, requirements to set the parameters for standardized interconnection agreements. These agreements will outline: (1) the obligations of the utility relative to customer notification and communication requirements; (2) time lines for completion; (3) allowances for pre-interconnection studies and charges; (4) provision for third party interconnection studies; and (5) disconnection and reconnection requirements.

These standardized agreements should incorporate specific interconnection standards adopted by the Institute of Electrical and Electronic Engineers ("IEEE") or other recognized standard-setting groups and require the use of standard applications, provided by the customer-generator to the utility.

2. Pre-Interconnection Studies

Interconnection of new generators to the distribution system affects system reliability. Therefore, customer-generators must coordinate generator additions with the distribution operator. The expense and time associated with these studies can make them a barrier to entry for the new customer-generator. The commission hereby requires each utility to perform pre-interconnection studies for customers at reasonable costs to the customer, and to set forth the terms and conditions of the same in a proposed tariff for approval by the commission. These requirements will require the utility to complete the study within a reasonable time, advise customers of its costs in advance, limit charges for redundant studies, provide the study results in writing, and provide similar features to facilitate customer interconnection. These requirements and parameters shall also: (1) allow qualified third parties to perform the studies, and require the utility to accept them under specified conditions; (2) allow third party verification of alternative solutions and technologies; (3) create safe-harbor exemption from the study requirements for smaller projects whose interconnection is unlikely to affect the distribution system; and (4) pre-certify certain equipment that meets certain standards set by such organizations as the UL so as to expedite installation and obviate separately conducted equipment studies.

3. <u>Distribution System Upgrades Required for Integration</u>

In some cases, the entrance of a new generator will require the utility to upgrade the distribution system, or install equipment to maintain its safety and reliability. There is a possibility that the required protective equipment already exists with the new generating facility. Disputes therefore may arise as to whether the utility is insisting on redundant equipment.

Accordingly, the commission requires the utility to: (1) accept certification of distributed generation equipment, which meets standards from qualified entities such as IEEE and UL; (2) train its personnel in new technologies relating to integration equipment; and (3) where new equipment is required to facilitate interconnection, propose an allocation of cost responsibility that recognizes both the costs caused by the generator and the system benefits, if any, derived from the new equipment. Each utility may establish detailed terms and conditions for the foregoing requirements, by proposed tariff for approval by the commission.

4. Responsibility for Control and Operation of Distributed Generation Equipment

The benefits of distributed generation to the grid may increase if the utility can dispatch the customer's units or coordinate their operation with the utility's own units. On the other hand, customers may wish to maintain control of the generation to assure sufficient power resources for themselves.

The commission hereby requires the utility to use its best efforts to negotiate contracts that allow the utility to dispatch the customer's generation unit where dispatching the unit is economical and feasible, and coordinate their operation with the utility's own units.

5. Indemnification and Liability Insurance

Generators create economic risks. Disputes may arise over whether customer-generators should have liability insurance, and in what amounts and forms it should be required. Allowing the utility to impose excessively high liability insurance requirements deters small distributed generation facilities.

Accordingly, the commission will not require distributed generators to carry a standardized amount of insurance, and hereby prohibits any utility from imposing a standardized insurance requirement for distributed generation projects. The commission allows each utility, however, to require that distributed generation customers disclose whether they intend to self-insure (and if so their means and capability of self-insuring) or if they intend to obtain an insurance policy (and, if so, in what forms and amounts), as part of the interconnection application process with the utility.

By this Decision and Order, the commission does not intend to eliminate the obligation for distributed generators to carry some form of adequate insurance, as the commission expects distributed generation customers to have insurance in forms and amounts that are commercially reasonable in each particular situation. This approach allows a customer-generator more flexibility in providing for adequate risk management of the project without the burdensome and potentially overly costly standardized insurance requirements.

6. Utility Communication with Customer-Generators

Prospective customer-generators should not have to contend with long delays in processing their applications, confusion over which persons within the utility are responsible for which matters, and unfamiliarity within the utility over the engineering and economics of distributed generation projects. Prospective customer-generators are also entitled to have their confidential information protected.

The commission, therefore, requires each utility to (a) establish a centralized point of contact for distributed generation applications, (b) train certain utility employees in distributed generation matters as appropriate, and (c) maintain the confidentiality of information the customer-generator deems confidential, unless the commission determines that disclosure is necessary to protect the public or as otherwise determined by the commission.

H.

Cost Allocation and Rate Design

To build and operate a distributed generation project, costs must be incurred by both the customer-generator and the utility. The customer-generator will incur the up-front capital costs for construction and installation, as well as ongoing operating costs such as fuel and maintenance. The utility will have to incur costs to accommodate the customer-generator. The utility-incurred costs include: (a) costs to complete interconnection and pre-interconnection studies; (b) costs incurred to acquire and operate generation, transmission, or distribution facilities necessary to provide electric service to the customer-generator (i.e., distribution system costs); (c) costs of utility system facilities, built on the expectation that the customer's load will be there, which would be rendered unrecoverable if the customer-generator reduces its purchases in favor of the customer's own generation (i.e., "unrecovered costs").

To ensure that only economic distributed generation projects are developed, and that there is no cost shifting from the customer-generator to other customers or to utility shareholders, the commission finds that utility-incurred costs must be allocated properly so that those costs that benefit the distributed generation project are borne by the project.

This principle is applied to interconnection costs, standby and backup service costs, and unrecovered utility costs, as discussed below.

1. Interconnection Costs

Interconnection agreements are necessary to ensure appropriate coordination between the utility and the customer-generator. The costs of interconnection vary with the size of the project.

The commission hereby requires that each utility require the interconnecting customer to pay for all costs of interconnecting, including the costs of system upgrades or network upgrades; however, if the interconnecting customer or generator can show that there are benefits to the utility system for such upgrades, it may apply to the utility for a credit reflecting these benefits, subject to commission approval.

2. Standby and Backup Service Costs

Customer-generators may want access to utility systems for standby services and backup power. Standby services are utility services that are available from an electric utility on an as-needed basis to replace or supplement power from the distributed generation facility. Included in the category of standby services are backup services, which supply energy or capacity during unscheduled outages of onsite generation. Currently only two Hawaii utilities, HELCO and KIUC, have standby charges.[64]

---

[64]HELCO has a Standby Rider A, which was approved by the commission by Decision and Order 18575, issued on June 1, 2001,

All the parties in this docket agree that standby and backup charges should be cost-based. There was no agreement on what those costs are and the record on this subject was not sufficiently developed for the commission to design actual standby rates.

Accordingly, the commission requires each utility to establish, by proposed tariff for commission approval, standby rates based on unbundled costs associated with providing each service (i.e., generation, distribution, transmission and ancillary services). The unbundled rates should represent, identify, and quantify the costs of providing standby services to distributed generation customers, with the costs based on each utility's latest recorded results for the most recently completed fiscal year, or other means acceptable to the commission.

3. "Unrecovered" Costs

To provide distribution service to customers, utilities incur capital costs based on expected loads. If a customer whose load was part of the utility's planning self-generates, the utility is left with costs incurred for that customer. This problem arises when these costs are recovered on a per kWh basis, since the customer's usage of the utility's power will decline, leaving the utility either to absorb these costs or shift them to other customers.

---

in Docket No. 99-0207. It became effective on June 5, 2001, and applies to customers with regular alternative supplier of electricity, other than HELCO. See HECO, T-5 at 17. KIUC's existing Rider S is applicable to customers with a demand of at least 30kW who regularly obtain electrical energy from a capacity source other than one owned by KIUC with a capacity of at least 30kW. See KIUC, Response to CA-IR-41(b).

Allowing a customer to leave the utility with surplus capacity, while the customer builds new capacity, leads to uneconomic bypass.[65] In that situation, one customer's gain is the shareholders' or ratepayers' loss. This zero sum result is not consistent with the public interest because it simply shifts costs rather than creating new value.

Therefore, the commission finds that standby fees must be set at a level allowing the utility to recover the costs incurred by the electric utility that are reasonably apportioned to the customer-generator. A carefully constructed standby charge will prevent uneconomic bypass, because an economically rational customer will not make the investment unless the sum of that investment, the operating costs, and the standby charge are exceeded by the savings on the customer's bill resulting from the investment (plus any revenues the customer might earn from permissible sales back to the grid).

As part of the review and approval of the standby rates discussed above, the commission will also consider whether there is a benefit to deferring the assignment of any unrecovered costs until a certain percentage of load has been lost to distributed generation applications. In doing so, the commission will encourage deployment of beneficial and economic distributed generation while providing protection to the utility. Once the percentage is reached, the commission can appropriately allocate

[65]Uneconomic bypass results if the sum of the new capacity cost and the running cost of the new distributed generator exceeds the cost of the existing utility capacity.

the charges for unrecovered costs to those whose new generation rendered these costs unrecoverable.

I.

Other Issues

1. Informal Complaint No. IC-03-098

On July 2, 2003, Pacific Machinery, Inc., Johnson Controls, Inc., and Noresco filed an informal complaint against the HECO Utilities related to their decision to provide utility-owned distributed generation to individual customer sites.[66] Pacific Machinery, Johnson Controls, and Noresco are engaged in the business of heating, cooling, energy conservation, and related services.

Given that the commission has determined that utilities are allowed to participate in distributed generation markets as: (1) an affiliate; or (2) as a regulated utility under the circumstances described in greater detail above, the informal complaint is now moot with respect to prospective business activities.

2. Net-Metering Facilities

Under HRS Chapter 269, Part VI, Net Energy Metering, certain small customer-generators that operate solar, wind turbine, biomass, or hydroelectric generating facilities, or a hybrid system of two or more of these types of technologies may sell electricity to the utility.

[66] Informal Complaint No. IC-03-098.

Net-metering facilities are a form of distributed generation. These facilities differ from other distributed generation in two ways: (1) net-metering customer-generators can sell excess energy to the utility until a certain cumulative production limit is met, and (2) HRS § 269-102(b) may prohibit charging net-metering customer generators any new or additional demand charge or standby charge.

Accordingly, to the extent that HRS § 269-102(b) applies, any requirements established or approved by the commission with respect to interconnection charges, standby rates and charges shall not apply to net-metering facilities pursuant to HRS § 269-102(b).

III.

Orders

THE COMMISSION ORDERS:

1. The policy of the commission is to promote the development of a market structure that assures: (a) distributed generation is available at the lowest feasible cost; (b) distributed generation that is economical and reliable has an opportunity to come to fruition; and (c) distributed generation that is not cost-effective does not enter the system. The commission will take those actions that are necessary to promote the installation of distributed generation that is economically efficient and reliable, including, but not limited to, the matters specified in Section II.A of this Decision and Order.

2. With respect to customer-sited distributed generation projects, utilities are allowed to participate in the distributed generation market only as either: (1) an affiliate; or (2) as a regulated utility, upon a showing that: (a) the proposed distributed generation project would resolve a legitimate system need, (b) it is the least cost alternative to meet that need, and (c) in an open and competitive process acceptable to the commission, the customer-generator was unable to find another entity ready and able to supply the proposed distributed generation service at a price and quality comparable to the utility's offering, as described in greater detail above.

3. With respect to the IRP process, to the extent that utility-owned distributed generation is one of the options with which the utility meets its supply-side resource needs, distributed generation is subject to the same scrutiny applied to other resource additions. The commission, however, does not require utilities to identify specific customer-sited distributed generation projects in the IRP process.

4. The commission requires that each utility establish reliability and safety requirements, by proposed tariff for approval by the commission, for distributed generation that is connected to the electric utility's distribution system.

5. The commission requires that each utility establish a non-discriminatory interconnection policy, by proposed tariff for approval by the commission, that entitles distributed generation to interconnect when it can be done safely, reliably, and economically. The commission also requires the utilities to

develop a standardized interconnection agreement, by proposed tariff for approval by the commission, to streamline the distributed generation application review process and eliminate long lead times that may lead to cancellation of a beneficial project, as more particularly described above.

6. To ensure that only economic distributed generation projects are developed, and that there is no cost shifting from the customer-generator to other customers or to utility shareholders, utility-incurred costs shall be allocated properly so that those costs that benefit the distributed generation project are borne by the project. This principle is applied to interconnection costs, standby and backup service costs, and unrecovered utility costs, as described above.

7. The HECO Utilities shall be allowed to pursue their CHP application in Docket No. 03-0366 and HELCO shall be allowed to pursue its CHP application in Docket No. 04-0366. The HECO Utilities and HELCO, respectively, shall amend their applications to provide facts relevant to ordering paragraph number 2 above.

8. The HECO Utilities shall be allowed to continue to utilize interconnection tariff Rule 14.H. until new amendments are approved by the commission.

9. HELCO and KIUC shall be allowed to continue utilizing their respective standby rates until new standby rates are approved by the commission.

10. Tariffs required in this Decision and Order shall be filed with the commission within six (6) months from the date

of this Decision and Order, provided, however, that tariffs containing affiliate requirements described in Section II.B. of this Decision and Order shall only be required prior to the utility entering into the distributed generation market through an affiliate.

11. To the extent any existing tariff or other regulatory provisions are applicable to any of the additional tariffs required to be developed by the commission in this Decision and Order, the utility shall be allowed to propose amendments to the same, as appropriate. The utility shall also be permitted to propose to the commission for its consideration other means that may be more efficient and appropriate, in lieu of a tariff, by which to accomplish the principles and policies established by the commission in this Decision and Order.

DONE at Honolulu, Hawaii JAN 27 2006.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By Carlito P. Caliboso
Carlito P. Caliboso, Chairman

By (EXCUSED)
Wayne H. Kimura, Commissioner

By Janet E. Kawelo
Janet E. Kawelo, Commissioner

APPROVED AS TO FORM:

Michael Azama
Michael Azama
Commission Counsel

03-0371.eh

CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing Decision and Order No. 22248 upon the following parties, by causing a copy hereof to be mailed, postage prepaid, and properly addressed to each such party.

DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
DIVISION OF CONSUMER ADVOCACY
P. O. Box 541
Honolulu, HI 96809

WILLIAM A. BONNET
VICE PRESIDENT
HAWAIIAN ELECTRIC COMPANY, INC.
HAWAII ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LTD.
P. O. Box 2750
Honolulu, HI 96840-0001

DEAN MATSUURA
DIRECTOR, REGULATORY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P. O. Box 2750
Honolulu, HI 96840-0001

KENT D. MORIHARA, ESQ.
MORIHARA LAU & FONG LLP
841 Bishop Street, Suite 400
Honolulu, HI 96813

H.A. DUTCH ACHENBACH, PRESIDENT & CEO
JOSEPH McCAWLEY, MANAGER, REGULATORY AFFAIRS
MICHAEL YAMANE, VICE PRESIDENT, STRATEGIC PLANNING
KAUAI ISLAND UTILITY COOPERATIVE
4463 Pahe'e Street, Suite 1
Lihue, HI 96766

BRIAN T. MOTO, ESQ.
CORPORATION COUNSEL
CINDY Y. YOUNG, ESQ.
DEPUTY CORPORATION COUNSEL
COUNTY OF MAUI
200 S. High Street
Wailuku, HI 96793

KALVIN K. KOBAYASHI
ENERGY COORDINATOR
COUNTY OF MAUI
DEPARTMENT OF MANAGEMENT
200 S. High Street
Wailuku, HI 96793

WARREN S. BOLLMEIER II
PRESIDENT
HAWAII RENEWABLE ENERGY ALLIANCE
46-040 Konane Place, #3816
Kaneohe, HI 96744

JOHN CROUCH
Box 38-4276
Waikoloa, HI 96738

RICK REED
INTER ISLAND SOLAR SUPPLY
761 Ahua Street
Honolulu, HI 96819

HENRY Q. CURTIS
VICE PRESIDENT FOR CONSUMER ISSUES
LIFE OF THE LAND
76 North King Street, Suite 203
Honolulu, HI 96817

SANDRA-ANN Y.H. WONG, ESQ.
1050 Bishop Street, #514
Honolulu, HI 96813

CHRISTOPHER S. COLEMAN, ESQ.
DEPUTY GENERAL COUNSEL
AMERANDA HESS CORPORATION
One Hess Plaza
Woodbridge, NJ 07095

LANI D.H. NAKAZAWA, ESQ.
OFFICE OF THE COUNTY ATTORNEY
COUNTY OF KAUAI
4444 Rice Street, Suite 220
Lihue, HI 96766

GLENN SATO, ENERGY COORDINATOR
c/o OFFICE OF THE COUNTY ATTORNEY
4444 Rice Street, Suite 220
Lihue, HI 96766

Karen Higashi

Karen Higashi

DATED: JAN 27 2006